Enabling US electric utilities to decarbonize and grow

Discover how systems thinking adds clarity to near-term emissions outcomes

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Electric utilities play a central role in economy-wide decarbonization

As transportation, buildings and industry electrify, emissions reductions largely depend on the power sector's ability to deliver carbon-free, reliable and affordable electricity at scale. While not all US electric utilities (utilities) have explicitly adopted decarbonization targets, a large share of US electricity customers are served by utilities operating under emissions reduction commitments. Over the past two decades, many utilities have lowered emissions while maintaining system performance, but the conditions shaping decarbonization outcomes have changed significantly.

Electricity demand is now growing faster than assumed in earlier decarbonization plans, driven by electrification, manufacturing expansion, data centers and broader economic shifts. As demand accelerates, emissions increasingly shift upstream into the power sector, even as electrification enables reductions elsewhere in the economy. Under these conditions, near-term emissions outcomes are increasingly shaped by system readiness.

The pace at which generation, transmission and distribution infrastructure can be planned, permitted, interconnected and financed, alongside affordability and capital recovery considerations, now plays a decisive role in determining when emissions reductions materialize. As a result, near-term emissions trajectories are unlikely to follow steady or linear paths. Utilities expanding their infrastructure to meet the rising load may experience slower or more volatile near-term emissions outcomes, even as they remain aligned with long-term, science-based pathways.

These dynamics make near-term emissions results harder to interpret and compare across utilities facing different growth, infrastructure and investment profiles. Absolute emissions inventories and targets remain the foundation for accountability and credibility, but traditional metrics increasingly require context. Clear interpretation depends on supplementing reported outcomes with system-level indicators like carbon intensity that explain how demand growth, capital deployment and infrastructure sequencing influence observed trajectories.

As US power system capacity expands to support economy-wide electrification, applying systems thinking can support how progress is evaluated and delivered under changing power system conditions. This report identifies a set of practical checkpoints investors and other stakeholders can use to evaluate and compare near-term progress, and a set of actions for utilities and system operators to consider to achieve their decarbonization goals.

Drawing on sector data, established frameworks and utility disclosures, it provides a system-level lens for interpreting near-term signals while keeping long-term objectives — particularly the mitigation of emissions in alignment with Paris Agreement science-based pathways — in view. Actions identified for utilities and other system actors responsible for planning, investment and execution include:

- **Pursue long-term emissions goals while adapting near-term measurement to identify the system context.** Sustained reductions in absolute emissions remain the destination, while transition plans provide transparency into how changing system conditions and constraints influence interim trajectories.
- **Use carbon intensity metrics to contextualize progress.** Where applied consistently and transparently, intensity-based measures can support interpretations by situating emissions trends alongside the growing electricity supply.
- **Scale grid investment to keep pace with electrification.** Timely investment in generation, transmission, distribution and flexibility is essential to maintaining reliability and affordability while enabling a broader economy-wide emissions reduction.
- **Strengthen transition credibility through collaboration and engagement.** Transition plans remain most decision-useful when they are iterative, informed by pilots and refined through ongoing engagement with investors, customers and other stakeholders.

Electric utilities drive economy-wide decarbonization and growth

Utilities sit at the center of economy-wide decarbonization, where electrification is shifting emissions reductions from end-use sectors to the power system. As transportation, buildings and industry move away from direct fossil use, the pace of emissions reductions increasingly depends on both the scale of electrification and the carbon intensity of the grid supplying that demand.[1,2] Based on U.S. Energy Information Administration (EIA) data, carbon dioxide emissions from the US electric power sector declined by approximately 38% from 2005 levels through 2025.[3]

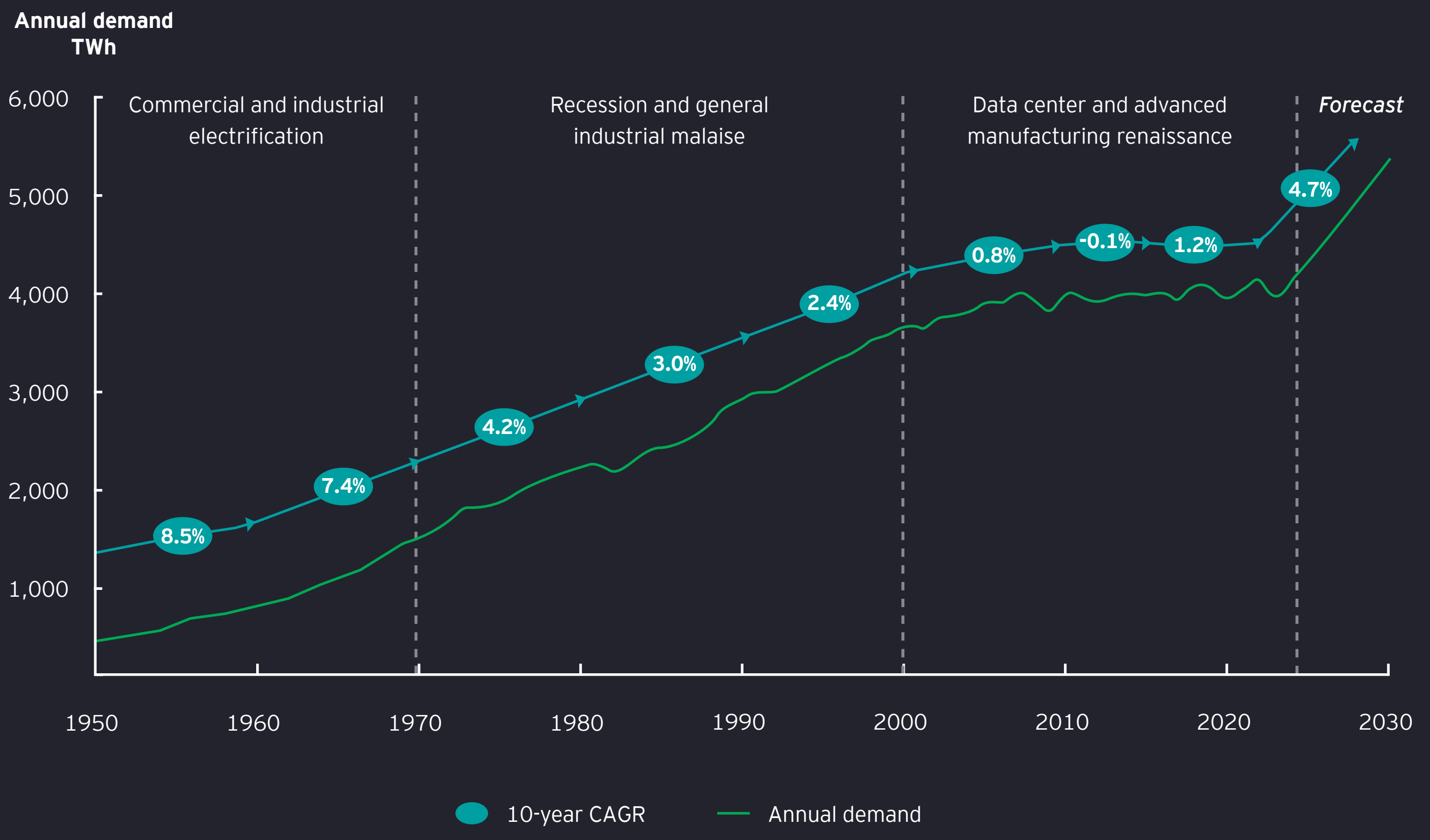
At the same time, the grid is entering a new demand era. The International Energy Agency (IEA) describes an emerging "Age of Electricity," driven by electrification and new sources of load, such as data centers.[4] US electricity demand projections have shifted markedly over the past several years, reversing longstanding assumptions of flat or modest growth.[5]

Changes in the EIA's long-term outlook reflect this movement: Comparing the 2018 and 2025 Annual Energy Outlook reference case projections, electricity sales through 2050 are anticipated to be more than 26% higher in the 2025 projections.[6]

Analysis through the EY Energy and Resources Transition Acceleration (ERTA) model projects that in the current trajectory scenario, electricity demand in the US increases by 18% between 2025 and 2030 and by 35% between 2025 and 2035, with an average of 3% year-over-year increase from 2025 to 2050.[7] As shown in the below figure, electricity demand growth reflects the rapid expansion of data centers, as well as rising demand from advanced manufacturing, supply chain reshoring and electrification. Together, these trends are projected to increase future power demand by 2.6% to 4.7% annually, with even stronger growth in the commercial customer class where data centers are concentrated.[8]

Figure 1. Electric demand growth

Historical and forecast US annual power demand, 1950–2030E TWh



Source: Lawrence Berkeley National Laboratory; Grid Strategies; U.S. Energy Information Administration

As the electricity demand grows significantly faster than the overall energy demand, it reflects the expanding role of electricity as a foundational input to economic activity. Local businesses and communities depend on reliable electricity to support economic development.

Electricity underpins manufacturing, digital infrastructure, commercial development and electrification across transportation and buildings. In this context, affordability and reliability become central considerations for local growth and competitiveness.

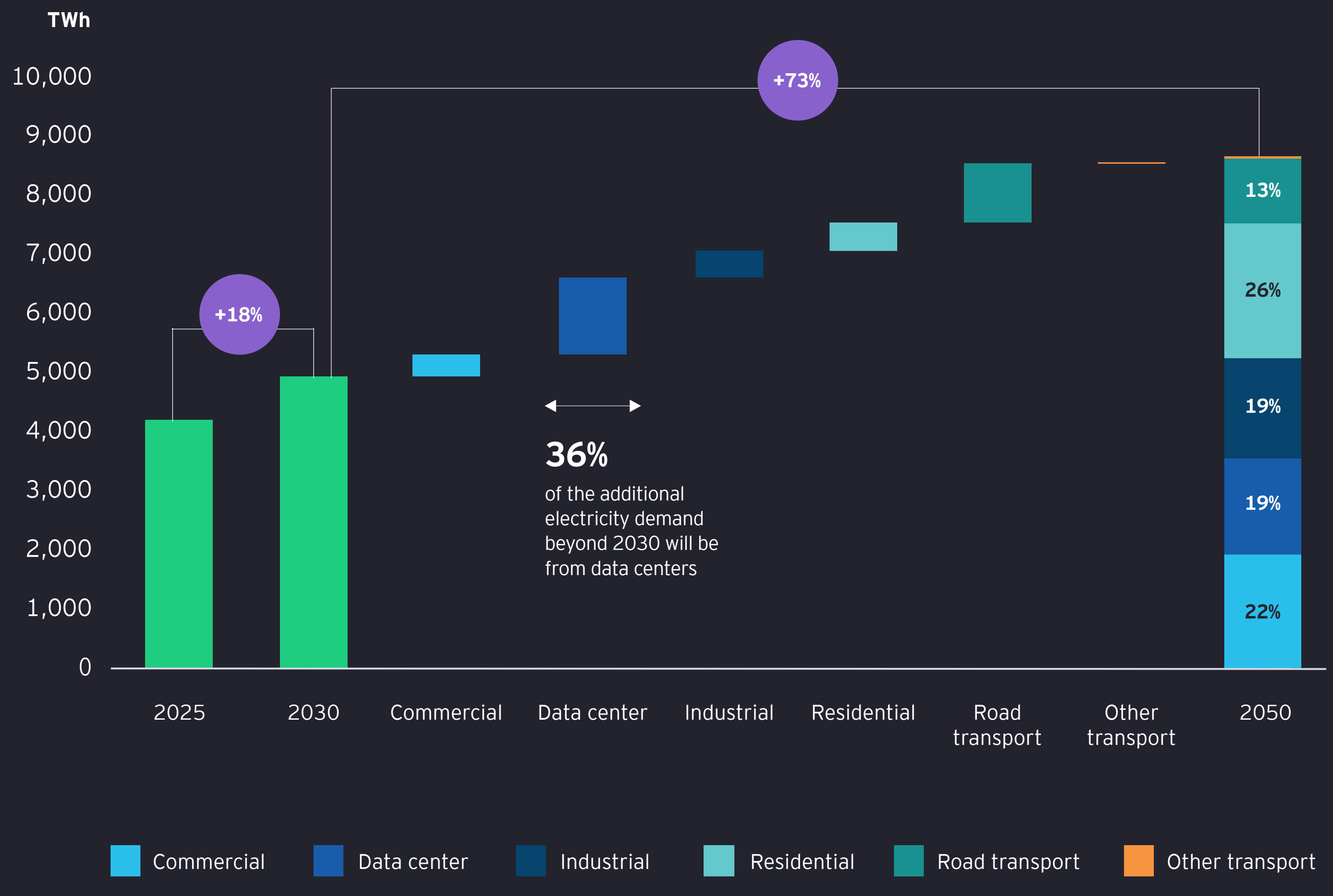
36%

of the additional electricity demand beyond 2030 will be from data centers*

*Analysis through the EY ERTA model

Figure 2. Demand growth driven by sector electrification

Electricity demand growth by end-use technologies in US (TWh)



36%

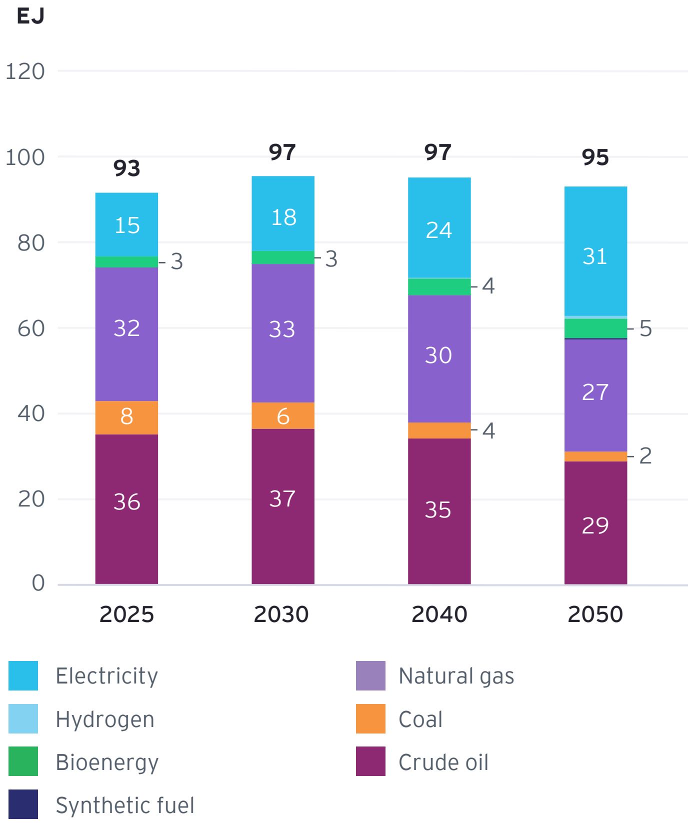
of the additional electricity demand beyond 2030 will be from data centers

Source: EY analysis of ERTA model, current trajectory

Electrification shifts emissions to the grid

Electrification is widely recognized as a core decarbonization lever. Electrifying vehicles, buildings and industrial processes enables low-carbon electricity to displace direct fossil fuel combustion and reduce economy-wide emissions.[9,10] Consistent with this transition, analysis through the EY ERTA model finds that the overall US energy demand is expected to increase only by 4% by 2030 and 2% by 2050. Although there is limited overall energy growth predicted, the ERTA model identified that electricity's share of the total US final energy demand is expected to increase from ~16% in 2025 to ~19% by 2030 and ~33% by 2050, as illustrated in the graphic below.[11]

Figure 3. US final energy demand by fuel type (EJ)



Note: Hydrogen and synthetic fuel <1 EJ

Source: EY analysis of ERTA model, current trajectory

Major reporting and assessment frameworks reinforce this view. For sustainability reporting, the European Union (EU) Corporate Sustainability Reporting Directive (CSRD) European Sustainability Reporting Standards (ESRS) E1 identifies electrification as a decarbonization lever that organizations use in transition planning.[12] The IEA similarly identifies electrification as a critical component of carbon reduction efforts, emphasizing the role of low-carbon electricity in displacing fossil fuels.[13] However, electrifying end-use demand can result in higher near-term emissions from the energy supply if the power sector emissions intensity does not decline in parallel.[14]

Therefore, while electrification is a primary pathway to carbon reduction efforts, it also increases the electricity demand. Whether emissions fall depends not only on carbon-free generation targets, but on how quickly utilities can scale and integrate supply, networks and system flexibility while maintaining reliability and affordability. In practice, the binding constraints are deliverability and the ability to permit, interconnect and operate new resources at scale rather than carbon-free firm-power technology availability alone. These trends create a central tension for electric utility sustainability goals.[15,16,17]

Systems thinking for evaluating the decarbonization impact of electrification

Systems thinking is an analytical approach that evaluates outcomes across interconnected components of a system rather than assessing individual elements in isolation.[18,19] In the context of economy-wide decarbonization, it emphasizes how structural changes in the energy supply enable emissions reductions in end-use sectors through the evolution of power systems, infrastructure and end-use technologies over time.

The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report emphasizes that decarbonization pathways depend on coordinated transitions. IPCC mitigation pathways show electricity becoming the dominant energy carrier as transportation, buildings and portions of industry electrify. Integrated IPCC assessment models project electricity will supply approximately half of the global final energy by mid-century in pathways consistent with limiting long-term warming. Specifically, the IPCC finds that electricity will provide 48% to 58% of the final energy in 2050 in pathways consistent with limiting warming to around 1.5 °C, and 36% to 47% in pathways consistent with limiting warming to around 2 °C.[20] As a result, the carbon intensity of electricity supply increasingly shapes the feasibility, pace and cost of emissions reductions in downstream sectors.[21,22]

This has important implications for how near-term electric utility decarbonization progress is interpreted. As the power system capacity expands to support economy-wide electrification, utility sector emissions may not decline in a linear manner. However, these dynamics can still represent net emissions reductions progress because lower carbon electricity displaces higher emitting fuels. Evaluating the progress through a systems lens, alongside absolute emissions trends, provides a more decision-relevant assessment of near-term outcomes aligned with long-term decarbonization pathways.

Long-term utility targets assume enabling conditions

The EY analysis of a benchmark set of publicly available disclosures for large US electric utilities shows that most have established long-term carbon reduction goals between 2045 and 2050. These targets typically cover scope 1 (direct emissions) and scope 2 (purchased electricity, steam, heating and cooling emissions), with varying approaches to scope 3 (value chain emissions). Across disclosures, utilities commonly identify technology availability, customer affordability and system reliability as prerequisites to achieving these goals, alongside the need for sustained investments in the grid infrastructure.

Disclosures frequently emphasize the importance of grid build-out and regulatory alignment as enabling factors that must progress in parallel with adding carbon-free generation and retiring fossil fuels. This reflects an acknowledgment that long-term ambition depends on system readiness, not solely on generation portfolios.

Utility disclosures illustrate how these goals are being framed in practice. The scope, accounting boundaries and interim target structures of these commitments vary by company and jurisdiction.

- **Duke Energy** has committed to achieving net-zero carbon emissions by 2050, with plans that include retiring coal assets, expanding renewables, modernizing the grid and maintaining nuclear generation as a firm and zero-carbon resource.[23]
- **Southern Company** has established a net-zero greenhouse gas (GHG) emissions goal by 2050, covering scope 1 emissions across its electric (and gas) operations, supported by a diversified generation strategy that includes nuclear, renewables and energy storage.[24]
- **Exelon** has adopted a goal to achieve net-zero GHG by 2050.[25]
- **AEP** has established a net-zero carbon emissions goal by 2050.[26]
- **Edison International** has committed to achieving net-zero GHG emissions by 2045.[27]
- **Xcel Energy** has adopted an aspirational goal to deliver carbon-free electricity by 2050. For more details, see the **Xcel Energy Case Study** later in the report.[28]

Most of the utilities benchmarked also disclose interim targets for 2030 to 2035, though near-term execution varies. While the long-term ambition is broadly aligned across the sector, the EY analysis indicates that progress toward interim targets depends heavily on the starting resource mix, regional market conditions, regulatory frameworks and the projected load growth, which continues to accelerate with data center growth.[29,30] As a result, utilities face differing challenges translating long-term commitments into near-term action and absolute emissions reductions.

Science-based emissions reduction pathways require power system readiness

Utility reporting on transition planning shows that their strategy for decarbonization depends on coordinated progress across several interdependent technology and infrastructure categories. These plans often point to the following five core action areas:

1. **Carbon-free generation build-out:** Large-scale deployment of wind and solar generation (and other zero-carbon resources) underpins efforts to decarbonize electricity supply.
2. **Grid modernization, hardening and expansion:** Continued investment in transmission, distribution and digital capabilities is necessary to connect new generation and serve rising electrified load.
3. **System flexibility:** Battery storage, demand-side response and advanced system controls help manage variability and peak demand as renewable penetration increases.
4. **Firm, dispatchable capacity:** Existing natural gas today and lower-carbon firm resources over time, are required to maintain reliability during periods of low renewable output and system stress.
5. **Scaling emerging carbon-free firm technologies:** Achieving longer-term carbon reduction targets depends on the commercial maturity, cost reduction and scalable deployment of next-generation firm resources, such as carbon capture and storage (CCS)-enabled thermal generation, green hydrogen and geothermal systems.

> Across disclosures, utilities commonly identify technology availability, customer affordability and system reliability as prerequisites to achieving long-term carbon reduction goals.

These elements are interdependent and, in many cases, sequential. In practice, early investment in networks, flexibility and capacity is often required to enable renewable scale-up while preserving system dependability and affordability under changing demand conditions.

Achieving low-carbon electricity can be accomplished by scaling carbon-free generation alongside grid infrastructure, flexibility and risk management capabilities, with significant investment often needed before emissions reductions fully materialize.[31] While renewable capacity is expected to expand substantially, periods of high peak demand and rising electrification mean that renewables alone may be insufficient to offset declining dispatchable capacity without complementary investments in networks, flexibility and firm resources.[32]

This deliverability gap, particularly transmission availability and grid congestion, now largely shapes how and when new generation can be brought online, even where carbon-free technologies are available.[33] In practice, the speed of permitting, interconnection and infrastructure expansion is becoming a determining factor in whether planned projects translate into operating, system-serving assets.

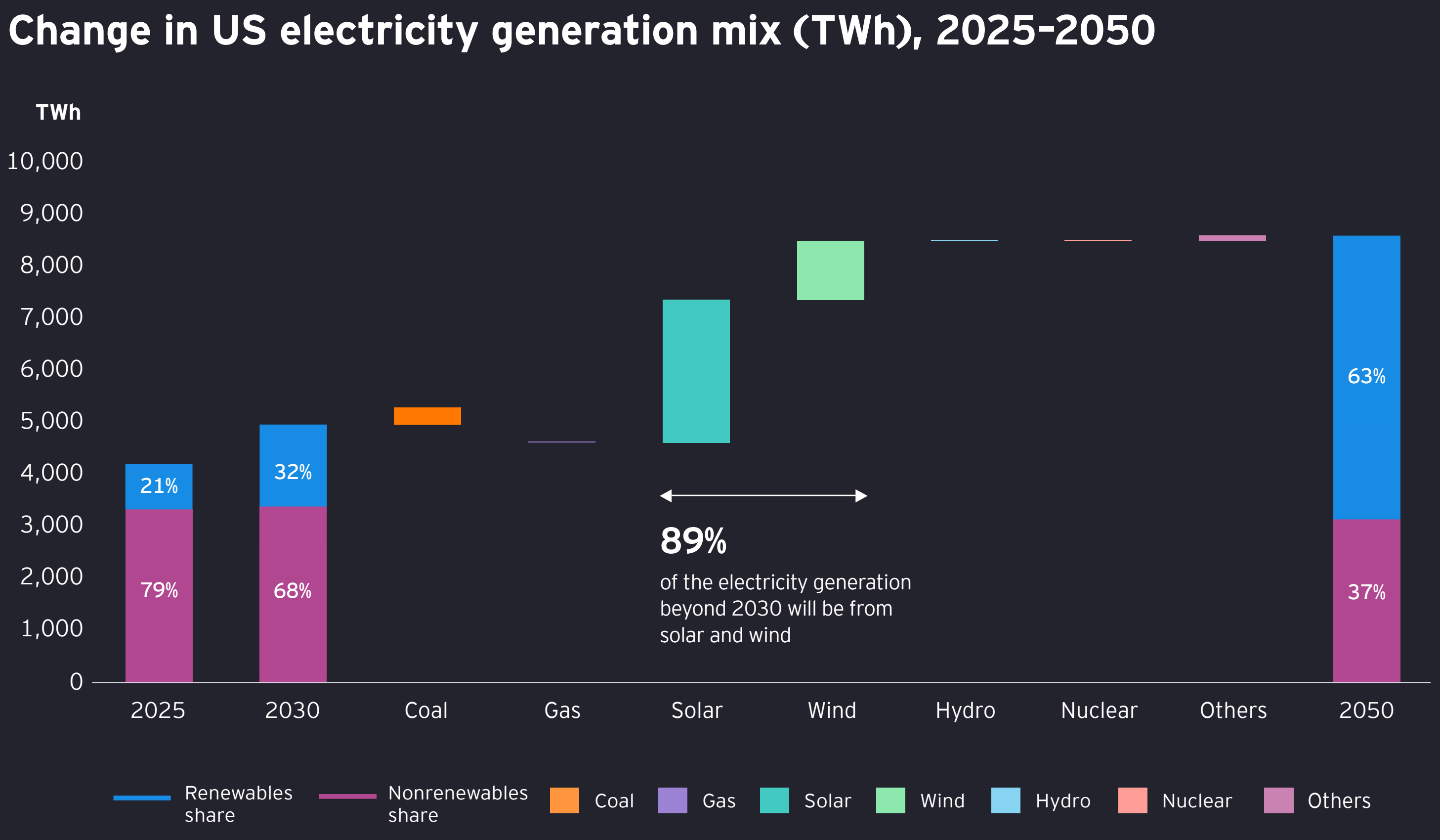
Carbon-free generation build-out continues

Over the past two decades, the US electric utility sector has made substantial progress scaling low-carbon generation. Coal retirements, sustained deployment of wind and solar, and operational improvements across power systems have significantly reduced emissions while maintaining performance. That trajectory is expected to continue, with US renewable energy capacity projected to more than double by the end of the decade. This would include the addition of approximately 266 gigawatts (GW) of new capacity and increasing demands on transportation, interconnection and system flexibility.[34] According to the EIA, electricity generation from wind and utility-scale solar increased from less than 1% of total generation in 2005 to approximately 17% in 2025.[35]

Broader system indicators reinforce this progress. A 2023 analysis by the U.S. Department of Energy (DOE) found that clean electricity sources provide more than 40% of total US power generation.[36] In recent years, solar, wind and battery storage have also comprised the majority of new US generating capacity additions, with solar representing the largest share of planned capacity.[37]

Looking ahead, renewables are expected to remain the backbone of new capacity additions through at least the 2030s. Projections suggest that by 2040, US solar capacity could increase from approximately 113 GW in 2024 to around 647 GW, while wind capacity could more than double from roughly 153 GW to 380 GW.[38] These trajectories position renewables as the primary source of incremental supply as the system moves toward long-term decarbonization.

Figure 4. Carbon-free generation build-out continues



89%
of the electricity generation beyond 2030 will be from solar and wind

Source: EY analysis of ERTA model, current trajectory

Renewables and storage continue to anchor planned capacity additions for electric utilities, with company strategies reflecting local resource conditions and regulatory context. Examples include:

- **Southern Company** describes a diversified generation strategy that includes renewables and storage alongside other sources.[39]
- **NextEra Energy** expects to build approximately 36.5 GW to 46.5 GW of new wind, solar and battery storage projects between 2024 and 2027.[40]
- **Dominion Energy** has more than 9 GW of solar in service or under development and is constructing the 2.6 GW Coastal Virginia Offshore Wind (CVOW) project.[41]
- **DTE Energy** plans to deploy 18,000 megawatts (MW) of renewables by 2042.[42]

At the same time, recent policy and market developments are reshaping expectations around deployment rates. Changes to US federal incentives have increased the uncertainty around post-2027 build trajectories. Recent projections suggest that US clean energy installations could decline 41% after 2027, resulting in a cumulative clean-capacity shortfall relative to prior forecasts.[43] Cost pressures related to tariffs, import dependence for key equipment, permitting delays, interconnection backlogs and supply chain constraints further heighten the sensitivity to policy durability and grid readiness.

Even with a continued carbon-free generation scale-up, many utilities emphasize the need to retain flexibility as conditions evolve. Across disclosures, the next phase of decarbonization is described as an integration challenge rather than a technology-availability challenge.

Interconnection and permitting timelines reshape outcomes

Across power systems, interconnection and permitting timelines are increasingly misaligned with the pace of both new generation development and the rising demand. Planning, permitting and constructing new transmission and distribution infrastructure can take five to 15 years while renewable generation projects are often developed within one to five years and large new loads, such as data centers, within one to three years.[44] These delays slow the pace at which carbon-free generation can contribute to system reliability and emissions reductions, even where project pipelines appear robust on paper.[45]

In the US, queues have expanded to unprecedented levels, with more than two terawatts of generation and storage capacity seeking grid access. Lawrence Berkeley National Laboratory found that thousands of gigawatts of generation and storage capacity remain stalled in interconnection queues, with median queue durations now extending well beyond four years.[46]

The Electric Reliability Council of Texas (ERCOT) alone has nearly 2,000 active generation interconnection requests, largely for solar and battery projects, representing hundreds of gigawatts of prospective capacity. At the same time, timelines from interconnection request to commercial operation continue to lengthen, particularly in the jurisdictional regions of the Federal Energy Regulatory Commission (FERC).[47,48] The FERC Order No. 2023 seeks to reduce interconnection backlogs and improve certainty by shifting toward clustered studies and updated cost allocation and readiness requirements; however, these reforms are being implemented amid historically lengthy permitting and construction timelines for grid infrastructure.[49]

Benchmarking indicates that electric utilities tend to cite permitting, siting and regulatory approval timelines as binding constraints on carbon-free generation deployment, grid expansion and system readiness. Even when projects are commercially viable and technically ready, the infrastructure required to connect and serve them often lags behind. The following utility disclosures illustrate how this challenge materializes in practice.

- **PG&E** identifies permitting and approval timelines as a challenge to achieving its 2040 net-zero energy system and notes that meeting California's climate goals depends on accelerating the transmission and distribution build-out beyond historical levels.[50]
- **Edison International** states that long planning, permitting and interconnection timelines pose a risk to meeting California's 2045 carbon-free power goals.[51]
- **Dominion Energy** highlights permitting and interconnection timelines as a key constraint on its clean-energy expansion, particularly for large projects.[52]

When load growth and project development move faster than permitting and interconnection processes, the practical outcome is delay. Projects remain stuck in queues, timelines extend and planning leans on existing assets to serve the growing demand. In this environment, interconnection and permitting processes play a decisive role in shaping the near-term outcomes, investment timing and the pace of decarbonization.[53,54,55]

Grid expansion, hardening and flexibility are prerequisites, especially for reliability

While carbon-free generation deployment continues at pace, the ability to connect, move and balance electricity reliably is determining whether new resources can deliver system-level emissions reductions. National laboratory analyses show that high-renewable systems rely heavily on transmission expansion, hardening, storage and demand-side flexibility to maintain performance during peak demand and extreme conditions.[56]

Without timely investment in long-distance, high-voltage and interregional transmission, renewable projects can remain effectively stranded, congestion costs rise, and utilities turn to localized solutions such as on-site generation or microgrids.[57,58]

Power system flexibility is the set of capabilities that allow the grid to balance the supply and demand under higher renewable penetration and a more dynamic load.[59,60] Core flexibility levers commonly identified in electric utility plans include:

- **Transmission expansion and congestion relief**, which connect renewable resources to load centers and enable greater regional resource sharing
- **Energy storage**, particularly utility-scale batteries that shift energy across hours and support peak demand
- **Demand-side flexibility**, such as demand response, managed electric vehicle (EV) charging and load shaping for large customers
- **Operational flexibility from firm and dispatchable resources**, which provide dependable performance during extreme weather and periods of low renewable output

World Economic Forum research reveals advanced economy grids operate at relatively low average utilization levels outside of peak periods. Improvements in system coordination, forecasting and load flexibility can unlock substantial latent capacity without an immediate physical build-out.[61] Therefore, flexibility enables the reliability and supports capital efficiency.

Recent utility-led projects illustrate how flexibility can partially mitigate constraints in the near term.

- **Portland General Electric** demonstrated that advanced system-level analysis and flexible resource optimization can accelerate large load interconnections by identifying latent capacity in the existing infrastructure. This enables hundreds of megawatts of new load to be served years ahead of traditional transmission upgrade timelines, highlighting the importance of flexibility and system optimization as further investments are explored.[62]
- **Duke Energy** emphasizes grid modernization, storage and demand-side programs as complements to renewable build-out, with more than 13 GW of new capacity through 2030 and significant investments in grid modernization and resiliency over the next decade.[63]
- **Southern Company** plans to invest more than $80 billion over five years to strengthen the grid and deploy advanced technologies, while maintaining dispatchable natural gas capacity to preserve the system's stability.[64]

The EY analysis further indicates that accelerated transmission build-out could significantly reduce total US power system costs over time, while failure to expand networks at pace increases congestion, curtails renewable output and delays decarbonization benefits.[65,66]

Resource adequacy and enabling capacity

The rapid expansion of wind and solar generation has materially reduced power system emissions, but these resources are more variable than the thermal units they replace. Power systems now require greater volumes of balancing resources, ancillary services and firm capacity to meet peak demand and extreme conditions. Natural gas continues to play a critical role in supporting reliability, particularly during periods of low renewable output, even as fuel delivery constraints introduce additional risks during system stress.[67,68,69]

These pressures are compounded by structural changes on both the supply and demand sides. Analysis through the EY ERTA model projects that in the current trajectory scenario, capacity in the US increases by 24% between 2025 and 2030 and by 49% between 2025 and 2035, with an average of 4% year-over-year increase from 2025 to 2050.[70] While the total installed capacity is projected to increase, firm and dispatchable capacity will decline as coal and other thermal resources retire. As the demand grows, systems will rely on a smaller pool of remaining controllable assets to provide essential services during constrained hours.

When grid expansion and firm capacity investment do not keep pace with the demand growth, systems may rely more heavily on existing resources for longer periods, even where carbon-free generation capacity is available.[71] In such conditions, operating considerations and cost pressures shape the pace at which generation portfolios can shift, reinforcing the importance of ahead-of-need investment in infrastructure and capacity resources.

Because reliability is driven by peak demand and system stress events – not average annual energy – capacity and flexibility often must be built ahead of the need to preserve resource adequacy as the resource mix becomes more weather-dependent.

This creates a central transition risk: If adequacy-focused investments in firm capacity, flexibility and enabling infrastructure lag behind load growth and retirements, systems may need to lean more heavily on existing dispatchable resources for longer.

49%

projected increase in firm capacity in the US between 2025 and 2035*

*Analysis through the EY ERTA model

Forward-looking adequacy assessments reinforce this challenge. The European Resource Adequacy Assessment finds that rising demand and higher renewable shares increase the importance of proactive capacity planning and continued investment in on-demand resources, flexibility and networks to preserve adequacy during the transition.[72] These findings mirror conditions observed in US markets, where dependability is now determined by the availability of resources during constrained hours rather than the total annual generation.

The FERC's seasonal monitoring practices emphasize that maintaining system integrity under more volatile demand conditions requires resources that may operate infrequently, but must remain available during periods of peak load or system stress.[73] These resources often include dispatchable thermal generation, such as existing natural gas–fired units and, in some regions, remaining coal- or oil-fired units that provide firm capacity during extreme weather events even if their annual capacity factors are low.[74]

The DOE similarly frames resource adequacy as a planning challenge as much as an operational one. Capacity investments must be planned and deployed ahead of anticipated peak demand to maintain system security as the load profiles evolve. As the electricity demand rises, adequacy becomes an ahead-of-need investment challenge. Outcomes depend on whether firm capacity, flexibility and enabling infrastructure are in place before the system is stressed, not after. In this context, investment sequencing plays a critical role in shaping near-term stability and longer-term decarbonization outcomes.[75,76]

Carbon-free, firm technology readiness is critical for long-term target achievement

Beyond near-term adequacy and integration challenges, longer-term decarbonization outcomes are also shaped by technology readiness. Despite significant progress across carbon-free generation and enabling technologies, no single clean firm resource is commercially available at scale today that can fully replace conventional on-demand generation across all power system conditions. The Clean Air Task Force defines clean firm electricity as dispatchable, low-emission generation that does not depend on weather conditions and identifies that such technologies are likely necessary to achieve reliable, cost-effective power systems.[77] Most emerging clean firm technologies, such as advanced nuclear and hydrogen technologies, are in varying stages of development and have not yet demonstrated this capability on a commercial scale. Collectively, power systems continue to rely on existing flexible resources while innovation efforts proceed.

In practice, this has shaped near- and medium-term utility strategies. Many disclosures emphasize scaling proven technologies, including renewables, storage, transmission and demand-side measures, while advancing pilots, demonstrations and regulatory frameworks that allow emerging carbon-free and firm options to mature. Preserving flexibility in resource planning enables utilities to integrate new technologies as they become technically and economically viable.

Capital and cost recovery shape what gets built

Decarbonization progress for power systems is shaped by technology and system constraints, as well as capital allocation, risk-return dynamics and regulatory cost-recovery frameworks. Across the US, planned investment levels reflect the scale of infrastructure transformation underway. Electric utilities collectively plan to invest more than $1 trillion in capital expenditures over the remainder of the decade, primarily focused on modernizing transmission and distribution networks and expanding generation capacity.[78]

At the same time, sustaining the transition over the longer term would require carbon-free power investment to continue rising, reaching roughly $435 billion annually by 2050 in the US — over double from current levels.[79] This sharpens the importance of capital allocations, cost recovery and affordability considerations.[80] Carbon-free generation technology is seeing declining costs, with utility-scale solar now the lowest-cost source of new electricity in the US at levelized costs roughly 18% lower than new gas combined-cycle generation, reinforcing the pace at which electrification is advancing.[81]

Achieving these energy transition objectives at a system level can be accomplished with a sustained increase in investments across low-carbon technologies and enabling infrastructure, such as grids and storage. An IEA analysis indicates that annual investment levels would need to rise substantially through mid-century to support carbon reduction pathways. At the same time, relative returns influence how quickly capital mobilizes. Returns on clean energy investments have historically delivered lower average returns, which can affect the investment pace, even where the long-term policy ambition is clear.[82]

Large new loads add another layer of complexity to utility investment decisions by increasing the cost recovery and cost allocation risk. Data center development and other large industrial loads often prioritize the speed to power under shorter-term contractual arrangements, while utilities must plan, finance and recover costs for assets with multi-decade lifespans.[83] This mismatch elevates the importance of tariff design, customer contributions and other risk allocation mechanisms to limit cost shifting to existing customers.

Utility disclosures illustrate how these considerations are being addressed in practice.

- **Southern Company** highlights base rate freezes through 2027 and 2028 in certain jurisdictions as it executes large capital programs.[84]
- **Dominion Energy** in Virginia established a separate GS-5 rate class for hyperscale data centers and other large-load customers, with long-term service commitments, minimum demand charges and customer cost responsibility provisions designed to limit cost shifting to existing customers.[85.86]
- **AEP** emphasizes affordability risk in a territory where the majority of its customers live in counties below the national median income and has implemented data center large-load tariffs at AEP Ohio.[87]

As the load grows more rapidly, utilities are often being called on to fund the infrastructure ahead of the need, bringing affordability and risk allocation to the forefront of energy transition planning.

Affordability hinders ahead-of-need investment

Reliability and decarbonization often require utilities to identify, permit and finance grid, generation and flexibility infrastructure well in advance of observable outcomes. However, regulatory and planning frameworks are often oriented toward incremental investments justified by near-term utilization, creating tension when ahead-of-need investment is required to support the rising demand.[88]

This sequencing challenge creates a clear affordability trade-off. Up-front investments in grid capacity, firm resources and flexibility can increase customer costs before system benefits are fully realized.[89] At the same time, deferring investments can expose customers to congestion, price volatility and performance risks, particularly as the load growth accelerates.[90] Recent trends in approved and proposed rate increases reflect this tension as utilities balance near-term affordability with longer-term system needs.

A changing risk environment is stretching reliability

Electric utilities are being asked to deliver multiple objectives simultaneously: Maintain high standards, keep electricity affordable and accessible, and decarbonize rapidly while also managing unprecedented load growth and structural changes in how power systems operate. While each of these objectives is necessary on its own, their interaction is placing increasing pressure on traditional planning and operating frameworks.[91]

Reliability requirements are becoming more challenging to meet as power systems transition toward higher shares of variable renewables and more dynamic demand. Historically, grid planning and operations were built around conventional generation portfolios, where system risk was dominated by rare, high-impact events. Under this model, uncertainty was limited and power system behavior was relatively predictable, with reliability standards built on the N-1 criterion designed to withstand the loss of a single major asset.[92,93]

As the resource mix evolves, this risk model is becoming more strained. In power systems with growing shares of wind and solar, electrified demand and distributed energy resources, system stress now arises from smaller but more frequent deviations, including forecast error, intra-hour variability, correlated weather impacts and localized congestion.[94] These deviations can be correlated across assets and time, creating compounding effects that traditional deterministic planning models are not designed to capture.[95]

Dynamics such as extreme weather events and aging infrastructure have direct implications for resource adequacy and performance metrics. Maintaining standards such as the loss-of-load expectation now require access to a broader set of flexibility resources, including dispatchable generation, storage, demand response and transmission. It also requires planning approaches that can evaluate power system performance under a wide range of correlated stress scenarios rather than relying primarily on average conditions or a limited set of contingencies.[96]

Rapid, concentrated demand growth adds further complexity by tightening planning margins and increasing uncertainty. Integrating faster-changing demand into networks and planning frameworks developed for more stable conditions raises new operational and resource planning challenges.[97]

In this context, reliability is becoming a binding near-term carbon reduction constraint. As uncertainty becomes more persistent and more correlated, meeting expectations depends on ahead-of-need investments in flexibility, networks and firm capacity, alongside planning approaches that explicitly account for stressed operating conditions rather than average cases.[98] How effectively systems adapt to this changing risk environment will play a significant role in shaping both near-term outcomes and longer-term decarbonization progress.[99]

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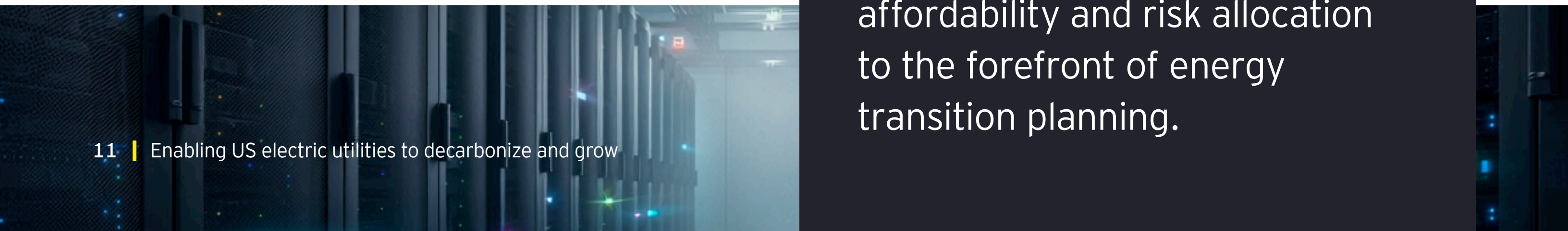

CASE STUDY

Xcel Energy navigating a changing landscape

Xcel Energy is an instructive example of how climate ambition interacts with rapidly changing system conditions while maintaining reliability and affordability for US electric utilities.

In 2018, Xcel Energy was the first major US investor-owned utility to establish a company-wide target to reduce carbon dioxide emissions from electricity generation and the first energy company in the nation to establish a vision for carbon-free electricity.[100,101] The goal was 80% by 2030 from a 2005 baseline, alongside a longer-term aspiration to deliver carbon-free electricity by 2050.[102] These commitments were accompanied by scenario analysis and public climate disclosures that assessed different technology and policy pathways under varying assumptions about load, resources and market conditions.[103,104] At the time these targets were established, Xcel Energy's load forecasts projected low single-digit annual growth, around 0% to 1% per year across its service territories, reflecting expectations of continued energy efficiency gains and historically flat demand trends.[105,106,107]

At the time Xcel Energy announced its goal, it had already reported a reduction of 38% in carbon dioxide emissions from electricity between 2005 and 2018.[108] Over the past eight years following the 2018 goal announcement, Xcel Energy further reduced carbon emissions from electricity by approximately 57% for the period from 2005 to 2024.[109] This is demonstrated by the reduction of Xcel Energy's carbon intensity of electricity delivered of 0.717 metric tons (MT) of carbon dioxide per net megawatt-hours (MWh) (MT/net MWh) in 2005 to 0.329 in 2024.[110] Reductions have been driven primarily by coal retirements, large-scale deployment of wind and solar resources, continued operation of existing nuclear facilities and operational optimization of its system.[111]

The situation: early ambition under changing system conditions

In recent years, Xcel Energy's service territories have experienced accelerated electricity demand driven by industrial activity, the electrification of transportation and buildings, and data centers.[112,113] The company expects retail sales to grow 5% through 2030.[114] This makes Xcel Energy a useful example for examining the challenges this transition poses.

Several of Xcel Energy's operating regions, particularly those within the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), have shifted to sustained demand growth driven by broader electrification trends. These incremental large loads can materially affect projected emissions outcomes, even as renewable resources continue to be added to the system.[115,116]

According to Xcel Energy, the scale and speed of demand growth exceeded the assumptions embedded in its Integrated Resource Plans (IRPs). For example, from 2019 to 2024, the Public Service Company of Colorado (PSCo) had relatively flat annual demand growth and is now forecasting 7% annual growth by 2031.[117]

As a result, the near-term path toward emissions reduction has been reshaped by factors largely external to the original planning context. Incorporating higher growth demand forecasts has required changes in system planning that affect resource portfolios, grid investment strategies and reliability considerations.[118,119]

Meeting the moment: continued ambition while navigating power system complexities

Xcel Energy operates approximately 11 GW of installed wind capacity, representing roughly 7% of total US wind capacity as of 2024. Its renewable and storage portfolio totals approximately 17 GW, while roughly 5 GW of coal capacity have been retired or converted since 2010. The company is planning an additional 7.5 GW of renewable generation, 1.9 GW of storage and 1,500 new transmission line miles between 2026 and 2030.[120] An example of new projects is the Sherco Solar project in Minnesota, developed on the site of a retiring coal plant and utilizing the existing transmission infrastructure.[121,122,123,124] Another new project is the recent agreement for the new Pine Island, Minnesota data center which is adding 1,900 MW new carbon-free energy and associated grid infrastructure including an advanced iron-air battery system.[125]

Despite this progress, Xcel Energy notes maintaining reliability under higher demand conditions requires continued access to dispatchable resources and storage. For example, the Southwestern Public Service Company (SPS) IRP focuses on substantial wind, solar and storage build-out while also recognizing the need for dispatchable natural gas capacity to support adequacy, manage variability, confirm reliability and mitigate cost risks. It additionally identifies the need for tech innovation to meet New Mexico's Energy Transition Act 2045 carbon-free goal.[126, 127]

Xcel Energy has been consistent in the position that emissions reductions beyond those reflected in its state approved IRPs and Clean Energy Plan portfolios depend on the future availability, cost and maturity of firm, non-emitting resources.[128]

While commercially available technologies could deliver substantial emissions reductions, achieving its long-term goal of a carbon-free electricity system would require firm and dispatchable clean technologies that are not yet available at the scale, cost or regulatory maturity needed for system-wide deployment.[129,130]

Xcel Energy addresses this limitation and related uncertainties in its climate risk assessments, scenario analyses and disclosures aligned with the Task Force on Climate-Related Financial Disclosures (TCFD).[131]

Grid infrastructure investment is treated as a critical enabling factor at Xcel Energy, which has outlined plans to invest approximately $60 billion across generation, transmission and distribution systems in the next five years.[132] These investments include expanded transmission in MISO and SPP to connect new renewable generation and reinforce the system under higher demand scenarios. Xcel Energy has characterized these investments as front-loaded, reflecting the need to build capacity and resiliency ahead of load growth.[133,134,135]

Systems enablement: outcomes and relevance to the future

Xcel Energy states it is on track to achieve 60% carbon-free electricity by 2027 and will further reduce its carbon intensity to 0.087 MT/net MWh in 2030, a 74% reduction from its 2024 carbon intensity.[136] Xcel Energy emphasizes affordability and reliability as nonnegotiable constraints on its decarbonization pathway. The company reports that customer electricity rates remain approximately 28% below the national average and that its system delivers 99.98% electric service availability, outperforming industry reliability benchmarks.[137]

Within this context, Xcel Energy believes trade-offs can emerge in the near term. Absolute emissions reductions, infrastructure build-out and affordability do not always move in lockstep in the near term, especially given technology and affordability constraints according to the company. While long-term emissions reduction objectives remain central, interim outcomes are increasingly shaped by the load growth, infrastructure timelines, technology readiness and affordability constraints. These challenges are shared across the sector and are not unique to an individual utility.

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Demand growth and grid limits reshape interim targets

Utilities are managing interim decarbonization commitments in a market context that complicates near-term execution. While long-term carbon reduction ambitions remain broadly aligned across the sector, near-term progress is experiencing heightened volatility in demand, costs, supply chains and policy conditions. Interim emissions trajectories are now being shaped by system constraints as much as by stated sustainability targets.

The EY Climate Action Barometer highlights a growing gap between long-term carbon reduction commitments and near-term progress across the energy sector. For electric utilities, this gap reflects the interaction of rising electricity demand, infrastructure constraints and the sequencing required to maintain consistency during energy transition phases.[138]

Recent emissions data illustrates these dynamics. In 2024, carbon dioxide emissions from the US electric power sector were largely flat year over year, increasing by less than 1%, while total electricity generation rose by approximately 3%.[139] That gap suggests the carbon intensity of electricity is declining, even when headline totals look flat. As a result, year-over-year absolute totals alone can only partially convey the progress while new carbon-free generation and enabling infrastructures are still being built.

Utility disclosures reflect this nonlinear absolute emissions reductions reality. Several companies explicitly note that progress toward long-term carbon reduction objectives will not follow a straight-line decline in emissions, particularly during periods of rapid structural change. These disclosures frame interim emissions outcomes as a function of system sequencing and infrastructure readiness rather than as indicators of backsliding from long-term commitments.

Viewing interim sustainability metrics alongside information on load growth, infrastructure build-out and power system constraints may help stakeholders understand this context. Short-term emissions trends alone may not fully capture whether utilities remain aligned with longer-term decarbonization pathways during transition phases characterized by rapid demand growth and evolving system conditions.

The near-term variability that electric utilities report is largely a function of system conditions, not utility-specific execution gaps. Interpreting progress therefore may be improved by viewing interim outcomes in the context of load growth, infrastructure sequencing and system readiness.[140]

Scopes define corporate climate reporting

Corporate GHG accounting in the US is anchored in the GHG Protocol suite of standards, including the Corporate Accounting and Reporting Standard and Scope 2 Guidance, among others, developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD).[141] These standards serve as the common foundation upon which sector-specific efforts are built.

These disclosures originated as voluntary corporate reporting, but have become central to investor evaluation, target-setting initiatives and more recently regulatory requirements. The resulting metrics operate at the corporate level, reflecting attributed emissions within defined organizational boundaries.

The accounting process defines the methodology for preparing corporate emissions inventories, including treatment of scopes 1, 2 and 3, as well as the use of fixed base years to track performance over time. The separate treatment of purchased electricity as scope 2 reflects the electric power sector's role as a shared input across the economy.

This framework has become the foundation for corporate climate disclosure across voluntary reporting initiatives and regulatory regimes, including disclosures under the International Sustainability Standards Board (ISSB) standards and the EU's European Sustainability Reporting Standards (ESRS).[142,143]

Growing stakeholder interest has emerged to understand decarbonization impacts that extend beyond attribution-based corporate inventories.

In response, the GHG Protocol's proposed Actions and Market Instruments (AMI) Phase 1 Progress Update highlights the demand for structured transparency. The AMI framework would address questions such as how corporate actions influence emissions outcomes beyond reporting boundaries and which sector-level impacts are associated with procurement decisions, market participation and the use of sold products. It would do so by encouraging multi-statement, supplementary disclosures that provide context for attributional inventories while maintaining clear separation to preserve consistency, comparability and auditability. This reinforces the primacy of attribution-based emissions accounting while recognizing the emerging demand for additional communication of broader emissions reductions.[144]

Organizations such as the Edison Electric Institute (EEI) and the Electric Power Research Institute (EPRI) play complementary, non-standard-setting roles by supporting interpretation and application within the electric power sector. EEI aggregates and publishes a broad set of standardized utility-level data, including electricity carbon intensity, resource mix data and sector-level emissions metrics, that many corporate electricity consumers rely on for scope 2 emissions calculations.[145] EEI also supports comparability through sector-specific standardized sustainability reporting templates and industry financial and grid investment benchmarking for stakeholders and investors to assess the transition readiness.[146,147] EPRI supports utilities through system-level research, modeling and target-setting tools, including the ongoing development of SMARTargets intended to help utilities assess emissions reductions targets that reflect operational realities like load growth and electrification dynamics.[148]

GHG Protocol–based inventories also serve as the foundation for corporate target setting and disclosure requirements. For example, the Science Based Targets initiative (SBTi) relies on them to assess corporate alignment with emissions reductions pathways.[149] Similarly, US and international disclosure requirements, such as California's climate disclosure laws and the EU CSRD, are grounded in corporate emissions reporting.[150]

Corporate emissions performance is measured using standardized inventories, while expectations continue to increase for greater transparency about how corporate actions influence system-wide decarbonization.

> Short-term emissions trends alone may not reflect whether utilities are aligned with long-term decarbonization during periods of rapid demand growth and system change.

Standards support comparable emissions disclosure

These frameworks support accountability by establishing consistent baselines, enabling year-over-year emissions tracking and supporting comparative disclosures across entities. The GHG Protocol's organizational and operational boundaries allow companies to quantify and track emissions in a consistent way. For the electricity sector, standardized emissions inventories and reporting mechanisms support transparency around the generation mix, emissions intensity and long-term trends, as reflected in the Environmental Protection Agency (EPA) and EIA's eGRID historical data and EEI standardized metrics.[151,152,153]

In addition, existing frameworks support market-based mechanisms for purchased energy through standardized scope 2 accounting. Scope 2 guidance establishes the consistent treatment of instruments such as power purchase agreements (PPAs) and energy attribute certificates, allowing companies to reflect energy procurement choices in their emissions reporting.[154] This facilitates corporate participation, resulting in the financing of renewable energy markets by linking procurement to disclosed emissions metrics and targets.

Attribution-based frameworks reinforce the role of absolute emissions reductions. Limiting global warming to well below 2 °C requires sustained declines in absolute GHG, as demonstrated in mitigation pathways assessed by the IPCC, rather than reliance on intensity improvements alone.[155]

They also support accountability by linking disclosed emissions data to corporate targets and public commitments. Investors rely on this information to evaluate transition risks, capital allocation decisions and alignment with decarbonization pathways, with surveys showing a growing demand for consistent, comparable emissions data in corporate disclosures.[156]

Limits of attribution during electrification

Unlike other sectors, electric utilities operate as a shared platform to decarbonize other sectors and thus must expand their generation and infrastructure to support this transition. As electrification is enabled, utilities may experience temporary increases or slower declines in reducing their own scope 1 emissions, especially when new capacity is required before sufficient low-carbon resources and grid reinforcements are fully deployed.[157,158]

Because utilities record emissions associated with electricity generation as scope 1, while emissions reductions enabled by electrification occur outside the utility's inventory reporting boundary, comparability can degrade as electrification accelerates. Utilities serving a rapidly growing electrified load may show higher absolute emissions or slower apparent progress toward near-term targets than with flatter demand, despite enabling emissions abatement. Further, customers relying on grid decarbonization to reduce scope 2 emissions may experience periods of stagnant location-based emissions factors, thus affecting their disclosures during phases of rapid demand growth.

When interim performance is evaluated through the prism of absolute emissions, this attribution structure can unintentionally discourage electric utilities from enabling an additional carbon-free load or accelerating electrification because doing so may increase the near-term reported emissions.

This challenge does not reflect a flaw in emissions accounting, but rather a limitation of applying attributional metrics to evaluate outcomes in a rapidly transforming energy system. Understanding this distinction can be useful for interpreting emissions trends, assessing comparability and evaluating investment signals for electric utilities during the transition.

Intensity metrics support investor interpretation

To supplement traditional emissions accounting, electric utilities already employ additional metrics that help stakeholders understand the emissions profile of the electricity they consume, beyond corporate-level inventories. These metrics are not used to replace scopes 1, 2 or 3 reporting, but to provide context about how the power system's performance evolves as electrification accelerates.

One commonly used supplementary metric is carbon intensity from electric generation, typically expressed as pounds of carbon dioxide electric generation per megawatt hour (lb CO_2e/MWh). This indicator reflects the emissions associated with electricity delivered to customers and is widely used by commercial and industrial customers in scope 2 emissions calculations and product carbon footprinting. In the US, utility-specific electricity carbon intensity and resource mix data are aggregated and published through EEI data sets while regionally standardized emission factors are published by the EPA through eGRID.[159,160] Together, these data sets support consistent interpretation of electricity-related emissions across markets.

While these metrics are particularly relevant for customers assessing the emissions implications of electrification decisions, they also serve a broader audience. Investors frequently use intensity trends to evaluate how utilities are managing decarbonization while serving the load growth and to assess the exposure to transition risks.

Consistent publication of intensity data, although it may not take into consideration varying demand growth and resource mix evolution, can support comparisons across utilities operating at different stages of system transformation as absolute emissions trajectories differ.

Some utilities also reference avoided emissions through consequential accounting approaches, which estimate the emissions displaced when electric technologies replace higher emitting fossil alternatives. These metrics are used to communicate the economy-wide effects of electrification programs and to contextualize customer-side emissions reductions alongside traditional intensity measures, demonstrating how electrification contributes to net emissions reductions beyond the power sector boundary.

Utility practice illustrates how these supplementary metrics are applied. Some utilities supplement intensity metrics with explicit recognition of electrification-enabled emissions reductions. PG&E, for example, discloses enabling emissions impacts to describe how low-carbon electricity delivery, EV adoption, building electrification and grid-level storage contribute to emissions reductions in other sectors.[161]

More broadly, the EU's CSRD and the associated ESRS require disclosure of energy consumption, emissions intensity and transition planning. ESRS E1 emphasizes transparency around the energy mix and scopes 1, 2 and 3.

System-level assessment is scarce in global frameworks

As electrification accelerates and investment in power systems scales, some frameworks supplement entity-level emissions disclosures with system-level indicators that assess how power systems are performing as a whole. Frameworks such as those developed by the Council of European Energy Regulators (CEER) use output-oriented systems indicators such as increased electrification, system flexibility, resiliency and continuity of supply, energy efficiency and the availability of data to market participants. CEER's electricity "smart grid" performance indicator framework is designed to support evaluating how networks perform as they adapt to the clean energy transition.[162]

Complementary analyses by the European Climate Neutrality Observatory use a broader set of economy-wide or system-level indicators, including electricity sector emissions trajectories, generation mix and electrification trends in energy consumption, to evaluate whether observed emissions trends across interconnected power systems are consistent with the EU climate targets.[163]

Although developed for the European regulatory context, these approaches align with a broader global shift toward supplementing corporate emissions metrics. This shift is increasingly relevant to investors and other stakeholders applying global frameworks, such as the aforementioned ISSB climate standard.

Context for investors beyond inventories

As electrification accelerates and capital investment in power systems scales, how decarbonization performance is measured has practical consequences for capital allocation, comparative assessments and investment signaling. While emissions data points are widely disclosed, the *2024 EY Global Institutional Investor Survey* finds concerns about the comparability, materiality and decision usefulness of sustainability disclosures.[164] For electric utilities in particular, climate transition plans increasingly serve as the primary vehicle through which investors expect emissions metrics to be interpreted, contextualized and connected to a forward-looking strategy.

Identifying emissions trends during electrification

These checkpoints are intended to keep the interpretation decision useful during the transition, improving comparability where possible while clarifying the context.

1. **Emphasize accounting discipline in emissions reporting**
   Attributional emissions accounting remains the backbone of credible reporting. Interpretation should reinforce, not blur, established boundaries and auditability. Decision-useful transition plans then connect emissions trends to the strategy, capital allocation and implementation assumptions without undermining the accounting discipline.

2. **Comparability depends on context**
   Near-term intensity and absolute emissions trajectories can be highly sensitive to demand growth and capacity additions, complicating direct peer comparison across utilities moving through different transition dynamics. When used for comparison, it may be helpful to read emissions trends alongside the drivers that explain "why now," such as the sequencing of retirements, new capacity additions and demand growth.

3. **System indicators explain the "why"**
   Investors in electric utilities and other stakeholders increasingly rely on a focused set of system indicators, such as the electricity emissions intensity, resource mix, capital allocation to transition-enabling assets and grid expansion, to interpret reported emissions trends in the context of system transformation. Because economy-wide decarbonization is assessed across sectors rather than at the level of individual entities, stakeholders may find it useful to interpret utility emissions trends in light of the system role that utilities play in enabling electrification and downstream abatement.

Future-shaping actions for electric utilities

Electric utilities can continue to enable broader US decarbonization through the delivery of carbon-free, reliable and affordable electricity. Many in the power sector continue to pursue the goal of long-term decarbonization, but the path is being reshaped by electrification, load growth, reliability pressures and affordability concerns. The choices made by electric utilities in the next few years will determine whether the sector can maintain its status as the backbone of decarbonization across the US economy.

As power system conditions change, electric utilities face four priorities that will shape the transition outcomes.

1. **Pursuing long-term emissions goals while supplementing near-term measurement to identify system context**

   Stakeholders likely will continue to expect utilities to maintain clear accountability for long-term reductions in absolute GHG emissions, which remains essential. However, utilities can discuss emission trajectories within the context of changing system conditions, including rising electricity demand and accelerated infrastructure build-outs. Climate transition plans provide a structured way to retain long-term emissions accountability while transparently explaining how load growth, investment timing and reliability considerations affect near-term outcomes.

2. **Carbon intensity metrics can contextualize transition progress**

   As the US energy system undergoes accelerated transformation, stakeholders will benefit from electric utilities maintaining strong accountability through absolute emissions targets. Additionally, utilities may consider supplementary, clearly defined metrics that offer a contextual understanding of localized system conditions and the transition progress. For example, emissions intensity metrics such as CO_2e emissions per unit of electricity supplied are widely used in energy system analysis. They can help assess whether growth in the electricity supply is being met with progressively lower carbon emissions.

   Consistent application of such metrics and the assumptions used to calculate them can help make them useful in decision-making. As electric utilities develop transition plans, there is value in alignment on a common set of supplementary metrics and assumptions so that disclosures are comparable and reflect shared system realities.

The Transition Plan Taskforce (TPT) recognizes electric utilities as system-enabling sectors whose transition plans should explain both entity-level emissions performance and how the company's strategy and investments align with, and contribute to, an economy-wide transition to a low GHG energy system. The TPT emphasizes that absolute emissions disclosures should be complemented by metrics and targets that track the delivery of transition actions and outcomes.[165,166] The examples below are illustrative only and are not intended to prescribe a specific set of indicators.

Examples of indicators the sector may consider:

- **Emissions intensity of electricity supplied tracked consistently over time.** This indicator can be used to support the interpretation of emissions trends in the context of the changing electricity demand and increasing economy-wide electrification rather than isolating utility performance from the effects of system growth dynamics.
- **Share of electricity supplied from low-carbon or carbon-free sources.** This reflects structural changes in generation portfolios. This metric directly affects downstream emissions across electricity-consuming sectors such as transport, buildings and industry.
- **Capital allocation to transition-enabling assets.** This includes carbon-free generation, transmission, distribution and system flexibility. This measurement signals the pace and scale of investments supporting the transition.
- **Transmission and distribution expansion indicators.** These are indicators such as for network upgrades or capacity additions. This indicator captures physical constraints and enabling factors for system-wide electrification and carbon-free energy integration.
- **Alignment of transition plans with national or sectoral science-based emission reduction pathways**. This metric provides transparency into how individual utility actions contribute to local economy-wide transition objectives.

When applied by the sector consistently and transparently, additional metrics can help inform planning, capital allocation and stakeholder dialogue. This can be particularly helpful during periods of rapid change. Importantly, these metrics should not be viewed as substitutes for absolute emissions accountability; rather, they provide additional insights into the localized system impacts.

3 Scale grid investment to keep pace with electrification

The pace of electrification and the share of electricity underscore the scale of the change ahead. Timely investment in generation, transmission, distribution and system flexibility can help address reliability risks and bottlenecks, which could increase and compromise affordability and slow economy-wide decarbonization.

4 Strengthening transition credibility through collaboration, pilots and engagement

Climate transition plans can support cross-sector alignment by clearly describing how utilities will meet the growing electrification demand while upholding reliability and affordability. To stay decision useful over time, transition plans should be iterative and updated regularly to reflect changes in the power system conditions, policy, technology readiness and demand trajectories.

Utilities can strengthen their credibility by testing approaches through pilots and by proactively seeking feedback from investors, customers and other stakeholders as part of these update cycles.

Maintaining a science-based ambition and clear accountability for long-term emissions reductions can support the credibility of decarbonization efforts. The sector's ability to demonstrate how providing low-carbon electricity enables larger absolute emissions reductions beyond the power sector will increasingly define the success of the transition.

Sector alignment on supplementary metrics used to assess the system-wide impact, including assumptions, can also strengthen credibility. Clear articulation of how grid investments, carbon-free generation and power system flexibility support electrification across end-use sectors can provide stakeholders with a more complete understanding of the progress. Ultimately, strengthening transparency, comparability over time and decision-useful disclosures will support informed oversight, sustained investments and continued progress toward economy-wide decarbonization enabled by low-carbon electricity. ▪

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Glossary

- **Absolute emissions target:** Absolute targets set a specific reduction in the total amount of GHG emissions by a certain date.[167]
- **Attributional accounting:** This is a type of GHG accounting that quantifies and tracks GHG emissions, removals and other accounting categories within a defined inventory boundary over time relative to a historical base year.[168]
- **Carbon-free generation:** In this report, it means carbon-pollution-free electricity generation, which is defined by the DOE as electrical energy produced from resources that generate no carbon emissions, including marine energy, solar, wind, hydrokinetic (including tidal, wave, current and thermal), geothermal, hydroelectric, nuclear, renewably sourced hydrogen and electrical energy generation from fossil resources to the extent there is active capture and storage of carbon dioxide emissions that meet EPA requirements.[169]
- **Decarbonization:** This is a term used to denote the declining average carbon intensity of primary energy over time.[170]
- **Energy demand:** This represents the amount of energy required to satisfy the needs and wants of a human population at a given time.[171]
- **Economy-wide:** In Paris Agreement–aligned usage, the term is applied descriptively to indicate GHG mitigation targets or actions that cover all major emitting sectors of a national economy rather than sector-specific measures, but this meaning is implicit rather than codified in treaty text.
- **Economy-wide GHG emissions reductions:** [see "Economy-wide"] This represents reductions over time of anthropogenic GHG emissions across all economic sectors, including energy, industry, transport, buildings, agriculture, waste and land use.
- **End-use sectors:** These include the residential, commercial, industrial and transportation sectors of the economy.[172]
- **Energy transition:** [Transition] An energy transition is a major structural change to energy supply and consumption in an energy system.[173]
- **Firm power:** This is power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.[174]
- **Firm resources:** These are generating or capacity resources that provide firm power.
- **Interim:** In this context, near term and medium term defined as 2026 to 2035.
- **Load growth:** [Electricity demand growth] This is a metric measuring an increase in electricity consumption over time measured by sales to commercial and residential customers.[175]
- **Long term:** In this context, this is mid-century, defined as 2045 to 2050.
- **Long-term decarbonization:** In this context, it refers to the sustained reduction in emissions consistent with pathways assessed by the IPCC by mid-century.
- **Resilience:** In this context, it's a measure of the ability of a power system to anticipate, prepare for, respond to and recover from potentially disruptive events, ideally while maintaining an adequate level of system function and with minimum damage or adverse impact.[176]
- **Resource adequacy:** This is defined as the ability of a power system to meet the electric power and energy requirements of customers within acceptable reliability limits and taking into account scheduled and unscheduled outages.[177]
- **Peak demand:** This is a metric measuring the maximum load during a specified period of time.[178]
- **Reliability:** This is a measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.[179]
- **System (electric):** In this white paper, this is a reference to physically connected generation, transmission and distribution facilities operated as an integrated unit under one central management or operating supervision.[180]
- **System transformation:** This is the sector-wide restructuring of power systems implied by Paris Agreement–aligned pathways, including rapid decarbonization of generation, large-scale deployment of low-carbon technologies, upgrades to transmission, distribution, system flexibility needed to integrate variable and distributed resources, and the retirement or conversion of high-emitting assets against which utilities' emissions trajectories are assessed.
- **Well below 2 °C**: This is a metric consistent with the Paris Agreement's overarching goal to hold the increase in the global average temperature to well below 2 °C above preindustrial levels.[181]

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